Economic Competitiveness of U.S. Utility-Scale Photovoltaics Systems in 2015: Regional Cost Modeling of Installed Cost ($/W) and LCOE ($/kWh)

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***Abstract* — Utility-scale photovoltaics (PV) system growth is largely driven by the economic metrics of total installed costs and levelized cost of electricity (LCOE), which differ by region. This study details regional cost factors, including environment (wind speed and snow loads), labor costs, material costs, sales taxes, and permitting costs using a new system-level bottom-up cost modeling approach. We use this model to identify regional all-in PV installed costs for fixed-tilt and one-axis tracker systems in the United States with consideration of union and non-union labor costs in 2015. LCOEs using those regional installed costs are then modeled and spatially presented. Finally, we assess the cost reduction opportunities of increasing module conversion efficiencies on PV system costs in order to indicate the possible economic impacts of module technology advancements and help future research and development (R&D) effects in the context of U.S. SunShot targets.**

***Index Terms* — Balance of system (BoS), bottom-up cost model, LCOE, photovoltaic system cost modeling, PPA, soft cost, solar energy, SunShot, utility-scale PV.**

I. Introduction

Generally, solar photovoltaic (PV) systems can be categorized as distributed generation (DG) solar PV or utility-scale solar PV based on system configuration and end-use customer. DG solar PV usually represents a smaller system capacity—typically less than 1 MW (could be larger than 1MW, however. Note that capacity in this paper is measured in direct current, DC)—than utility-scale solar PV. DG systems are often sited on residential or commercial roof-tops and are connected to the local utility distribution grid. By contrast, utility-scale PV solar is ground-mounted, typically larger than 1 MW and the electricity produced is sold to wholesale utility buyers from the grid through a power purchase agreement (PPA). The scope of the analysis herein is limited to the modeling of installed cost and levelized cost of energy (LCOE) for a U.S. utility-scale PV system.

As the third-largest utility-scale PV market in the world [1], following China and Germany, the United States has seen utility-scale PV become the largest solar segment since 2012, as shown in Fig. 1. The recent rapid installed capacity growth in the U.S. has been primarily driven by the utility-scale PV segment, which experienced a 144% Compound Annual Growth Rate (CAGR) during 2009-2014 compared to a 44% CAGR for the residential segment, and a 50% CAGR for the commercial segment during the same period. Overall, the U.S. utility-scale PV segment started slowly (cumulative 23 MW of installation in 2007, or 4% of total solar cumulative installation), but has grown consistently to dominate today's U.S. solar profile (cumulative 9.1 GW installation in 2014, or 51% of total solar cumulative installation). This historical trend in part indicates that, despite the additional development requirements for land acquisition, environmental permitting, or transmission lines, centralized large utility-scale PV has been widely deployed in the U.S. This is likely due to the decreasing upfront capital investment (namely, installed cost) per Watt, solar Investment Tax Credit (ITC), Renewable Portfolio Standards (RPS) mandates [2] at the state level, and the role as a long-term hedge against electricity price volatility [3].

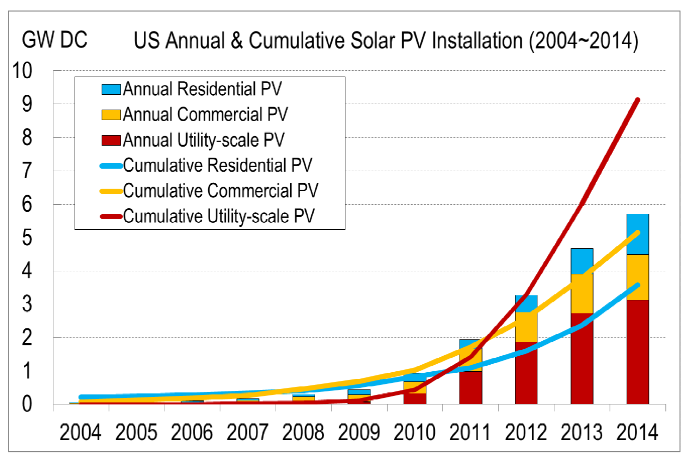

Fig.1. U.S. annual and cumulative installation of solar PV (2004~2014) [1].

Historically, U.S. utility-scale PV all-in installed costs have been analyzed as a national average, and reported in terms of dollars per Watt ($/W). For instance, past NREL studies [4] employed an in-house bottom-up system cost model to benchmark average U.S. PV system costs (including all direct construction costs, installed costs, overhead, and profit margins, but excluding subsidies and investment tax credits), and regional factors were not incorporated. This paper,

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however, includes local structural design criteria for wind speed and snow loading, local labor wages, local material costs, state sales taxes, and environmental permitting costs that vary significantly in different U.S. regions, can result in wide variations in regional installed costs.

In order to assess the economic competitiveness of utility-scale PV with a high geographic granularity, these regional factors need to be analyzed and incorporated into a bottom-up system cost model. In this paper, a new PV system cost model was developed to capture installed cost variations ($/W) across U.S. regions. This cost model is established based on the actual engineering design for a generic utility-scale PV system, with cost estimations for each construction and development activity.

Because installed costs alone do not convey the competitiveness of PV systems in electricity generation markets, the regional installed costs are further combined with an energy production model (NREL's System Advisor Model, or SAM) to compute real LCOE in dollars per kilowatt-hour ($/kWh) for various locations. Combined improvements in regional PV system installed cost and real LCOE can better help the solar PV industry to achieve $1/W installed cost and $0.06/kWh LCOE targets by 2020, as part of the U.S. Department of Energy (DOE) SunShot Initiative [5][6]. They can also measure which states are closer to those targets. Low polysilicon and PV module prices, and low manufacturing profit margins [7] in today's PV industry indicate that system-level cost modeling and non-module component cost reduction pathways are gaining more attention for achieving those targets.

The final results of the regional installed costs and LCOE modeling are intended to inform investors, project engineering, procurement, and construction (EPC) contractors, project developers, decision makers, and other PV industry stakeholders of the geographically differentiated nature of potential PV system costs and performance. This bottom-up system cost model may also benefit PV manufacturing and research and development (R&D) by estimating the economic impact of module conversion efficiency on the total installed costs.

II. REGIONAL COST MODEL FOR U.S. UTILITY-SCALE PV SYSTEMS

Bottom-up system cost modeling estimates the total upfront capital costs incurred during PV system installation, construction, development, and financing. Note that available U.S. incentives for solar energy are not considered in the installed cost, but are considered in the real LCOE. The overall bottom-up cost structure of our model is presented in Fig. 2. Overall, total PV system upfront capital costs are broken into EPC costs and developer costs. An experienced EPC is typically hired by a developer for construction tasks. Detailed descriptions of modeled cost categories follow.

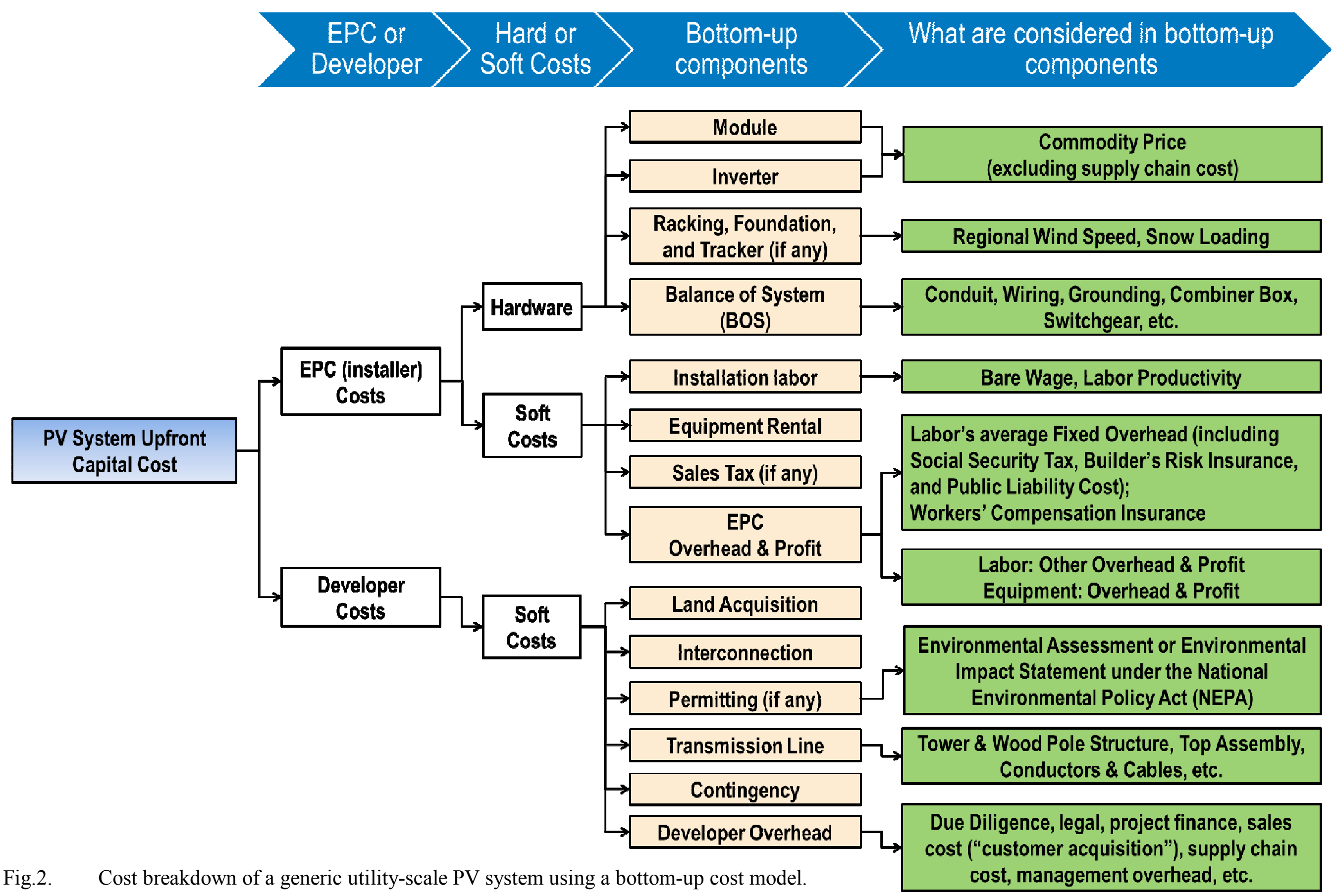

Fig.2. Cost breakdown of a generic utility-scale PV system using a bottom-up cost model.

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• *EPC Hardware Costs:* include the upfront capital investment in the physical assets that provide the useful life of a utility-scale PV system on the ground. This includes all of the required materials for completing construction and commissioning. In general, hardware falls into four subcategories–"PV module", "Inverter", "Racking" (including foundation and one-axis tracker, if any), and balance of system, or "BoS." Average bulk prices in 2015 for modules ($0.65/W) and inverters ($0.11/W) are assumed [8]. Racking components include supporting structural and mechanical components, such as equipment pads, foundations, racking hardware, module mounting hardware, and tracker hardware (if a one-axis tracker is used). Lastly, BoS includes all of the electrical components, such as conduit, grounding, wiring, cable, combiner boxes, and PV combining switchgear.

Most developers typically provide the EPC with modules, inverters, or even racking components to avoid the additional intermediate transaction cost. Thus, both module and inverter costs usually belong within the "Developer Cost" category. However, in this paper, for cost benchmarking and comparison purposes, module and inverter are still placed under the "EPC Cost" category for consistency with our previous reports.

• *EPC Soft Costs*: Traditionally, "Soft Costs" in construction refer to the expenses that are not related to direct construction materials or labor. However, in the context of solar system installation, soft costs are defined differently [9]. For EPC soft costs, they include "Labor cost", "Construction equipment cost", "sales tax", and "EPC overhead & profit". "Labor costs" include (1) all bare wages paid to employees, (2) additional cost of employee benefits, such as worker's compensation insurance, and (3) other fixed overhead costs, such as federal and state unemployment costs, social security taxes, and installer's risk insurance [10]. In this model, three labor rate databases are used, as presented in Table 1.

TABLE I

LABOR RATE DATABASES INTRODUCTION (2015)

Database Sources:	Definition
BLS Statistics Survey [11]	***Open-Shop Wage***, decided by employer and employee (thus, fair market wage), surveyed by Bureau of Labor Statistics (BLS)
Davis-Bacon [12]	***Prevailing Wage***, for projects funded or assisted by state/federal government, decided by Department of Labor
RS Means [10]	***Union Wage***, decided by labor contract between labor union and contractor's management, collected by RS Means Building Construction Cost Data

In each labor database, three basic construction occupations are adopted: Common laborer, Electrician, and Equipment Operators. The U.S. average labor rates for those three occupations are compared in Table II.

TABLE II

U.S. AVERAGE LABOR RATE COMPARISON, $ PER HOUR (2015)

Database Sources:	Common Laborer	Electrician	Equipment Operators
BLS Statistics Survey (Median Average)	16.38	25.14	22.20
Davis-Bacon (Prevailing Wage)	23.18	40.98	32.48
RS Means (Union Wage)	28.89	42.44	38.32

Although EPCs and developers tend to employ low-cost non-union labor (presented by BLS survey in this model) for PV system construction when possible, union labor is sometimes mandated: construction trade unions may leverage the public review period in the environmental permitting process to negotiate with local jurisdiction and EPC/developer and thus may influence solar project permitting process. Fig. 3 shows 2014 utility-scale PV installation capacity (MW) and unionized labor percent in each state. Unionized labor percent represents the percent of employed workers in the overall construction who are union members.

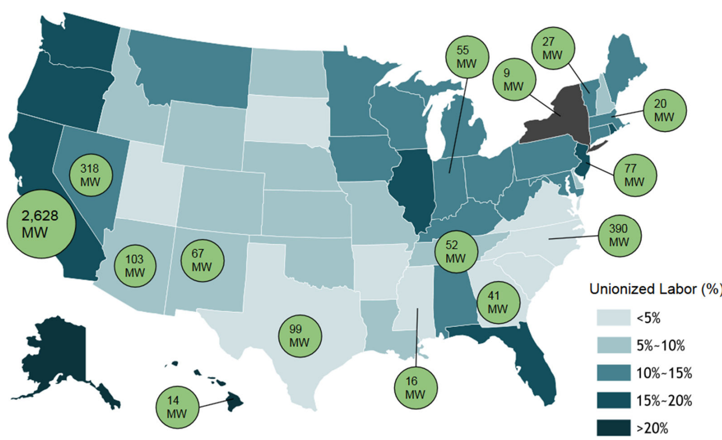

Fig. 3. 2014 U.S. utility-scale solar PV installation and unionized labor rate by state [13][14].

"Construction equipment costs" include operating costs, such as the fuel and rental or lease payments. Sales tax is incorporated on top of the hardware costs (except for modules and inverters) where applicable. It should be noted that 8%~10% is assumed as the estimated EPC overhead and profit [8] (namely, a markup on material, equipment, and labor costs). For project sizes less than 10 MW, 10% EPC overhead and profit are used; for project sizes over 100 MW, 8% EPC overhead and profit are used; for project sizes between 10 and 100 MW, linear interpolation is used [8].

Both EPC hardware costs and EPC soft costs are driven by region-specific structural design criteria, such as wind speeds and snow loading, and thus the resulting differences in installed costs can vary significantly across the country. To

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incorporate these cost drivers, a structural design tool based on American Society of Civil Engineers (ASCE) design code [15] and a construction cost estimating tool are utilized to determine the EPC hardware costs (including racking, mounting, and foundation) and related EPC soft costs (including related labor and equipment hours required in any given U.S. location).

• *Developer Hardware Costs*: include "Transmission line", or so-called generation-tie, or "gen-tie" line" costs. For large-scale remote PV sites, such lines carry the high level voltage, for instance, 230 kV AC (stepped up from medium level 34.5 kV in the solar facility site) to the off-site substation. For small-scale urban-sited PV systems, typically an on-site substation is overbuilt so that no transmission lines are needed. Spur lines link to the on-site substation with entrances at, for instance, 13.8 kV. Overall, modeled transmission line distance varies from 0 to 5 miles in different sites. In this model, for project sizes less than 10 MW, 0 miles is used; for project sizes over 200 MW, 5 miles is used; for project size between 10 and 200 MW, linear interpolation is used. For instance, in the model, we estimate that a typical 20~30 MW PV system would need a 0.4~0.5 mile transmission line and $1.13 million per mile for the infrastructure cost.

• *Developer Soft Costs*: defined as the other non-construction activity costs incurred from project initiation to commissioning. Developer costs include:

(1) Leasing or acquisition of land from landowners. This land acquisition cost is assumed as $0.03/W in the model [4].

(2) "Permitting fees", including environmental studies and permits, and any other entitlements required to construct and operate the system. The permitting cost depends on the issues at stake, such as: natural and human resources impacted, including threatened and endangered species, and cultural resources. Any proposed project on land that has multiple issues will most likely cost more in application processing than a proposed project on land that has fewer issues or conflicts. For instance, in California, a project would go through the NEPA (National Environmental Policy Act [16]) process, during which the Bureau of Land Management (BLM) will determine what type of environmental analysis needs to be completed (Environmental Assessment, or Environmental Impact Statement). NEPA requires federal agencies to consider alternatives to the federal action. The NEPA process includes public scoping, writing a draft analysis, soliciting public comments on the draft analysis, writing a final analysis, and then writing a decision document. Each of those basic steps requires specific work. In this paper, permitting fees are included for states with high federal land percentage, including Nevada (85%), Alaska (69%), Utah (57%), Oregon (53%), Idaho (50%), Arizona (48%), California (45%), Wyoming (42%), New Mexico (42%), Colorado (37%), Montana (30%), Washington State (30%), and Hawaii (20%) [17]. For other states, permitting fees are not modeled due to the low federal land percentage. Typically, BLM permitting costs for California vary between $200,000 and $1 million, with $500,000 per project as the typical value in this range [8]. In addition, BLM permitting in California requires collaborations among multiple entities, including the California Energy Commissions and agencies from federal, state, county, tribal, and military levels. These collaborations and coordination largely increase the time and related labor costs. For other states, a lower environmental permitting cost ($250,000 per project) is estimated in the model. Although there is a chance of locating the solar generation facility on private land in lieu of federal land, it is not very likely to avoid BLM permitting costs – because the project may need (a) access roads that traverse BLM federal land to enter the site, or (b) transmission lines that traverse BLM federal land. For both cases, BLM will evaluate the entire site including the private and federal lands.

(3) "Interconnection costs" refer to system impact assessment study and fees required for connecting the solar system to the grid [18]. Interconnection cost is estimated as $0.03/W [19].

(4) "Contingency" refers to an allowance accounting for project uncertainties and risks, including weather, change orders, and material price fluctuations during construction [20]. In the model, average contingency is assumed at 4% of all construction and development costs [8].

(5) "Developer overhead" refers to project due diligence (justification study, site visit, system evaluation, etc.), legal services, project finance, module/inverter/racking supply chain cost, sales cost, and management fee. Developer overhead, a markup on total EPC and developer costs, varies between 10% and 15% [8]. In the model, for project sizes less than 10 MW, 15% overhead is used; for project sizes over 100 MW, 10% overhead is used; for project sizes between 10 and 100 MW, linear interpolation is used.

Note that developers typically use an IRR target or a specific PPA to determine the project's Net Present Value (NPV). Thus, the value of a PV system, in terms of NPV, is dependent on different corporate strategies, capital structures, market competition, local electricity rates, etc. In this paper, "cost approach" is used for PV system installed cost ($/W), and "income approach" is used for PV system LCOE ($/kWh)

Model inputs and assumptions are summarized in Table III.

TABLE III
UTILITY-SCALE PV SYSTEM MODEL INPUTS AND ASSUMPTIONS IN 2015

Model components:	*Model inputs:*
Module	$0.65/W commodity price
Inverter	$0.11/W commodity price
Racking, foundation, tracker (if any), equipment rental	Determined by wind speed, snow loading, and material cost index by state
Balance of System	Determined by the size of the PV system
Installation labor	Both non-union and union labor are considered

Sales tax (if any)	Determined by location
EPC overhead & profit	< 10 MW, use 10%; > 100 MW, use 8% 10~100 MW, use linear interpolation
Transmission line (gen-tie line)	< 10 MW, use 0 mile; > 200 MW, use 5 miles 10~200 MW, use linear interpolation
Land acquisition	$0.03/W
Interconnection	$0.03/W
Environmental Permitting (if any)	$500,000 for California $250,000 for other states
Contingency	4%
Developer overhead	< 10 MW, use 15%; > 100 MW, use 10% 10~100 MW, use linear interpolation

III. RESULTS FROM UTILITY-SCALE PV SYSTEM MODEL: INSTALLED COST

The modeled EPC and developer cost results are presented in Table IV. Four cases are discussed: (A) fixed-tilt & non-union labor, (B) one-axis tracker & non-union labor, (C) Fixed-tilt & union labor, and (D) one-axis tracker & union labor.

• *EPC Costs*: Based on Table IV, the largest two drivers for EPC cost in the same location (California in this case) are the fixed-tilt/one-axis tracker option and the non-union /union labor options. In Fig. 4, for instance, if a one-axis tracker is adopted, the cost premium is about $0.11/W in Case (B) compared to Case (A); if union labor is used, the cost premium is about $0.21/W in Case (C) compared to Case (A). On the other hand, only $0.04~0.05/W in EPC cost savings (mostly from labor cost saving) can be achieved from a larger system size. Thus, the economies of scale benefit for EPC costs are relatively limited.

• *Developer Costs*: Based on Table IV, the largest drivers for developer cost in the same location (California in this case) is the system size. In Fig. 5, for instance, when system size is increased from 10 MW to 100 MW, $0.11/W can be saved and the majority of the saving comes from declined permitting and developer overhead for a larger system size.

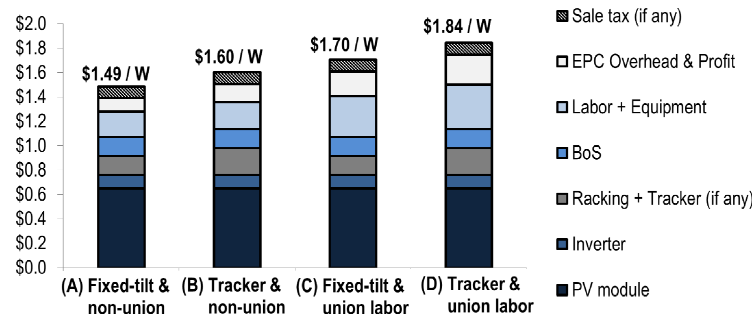

Fig. 4. 2015 "EPC Costs" breakdown in California (numbers from Table IV: system size = 100 MW, module efficiency = 16%).

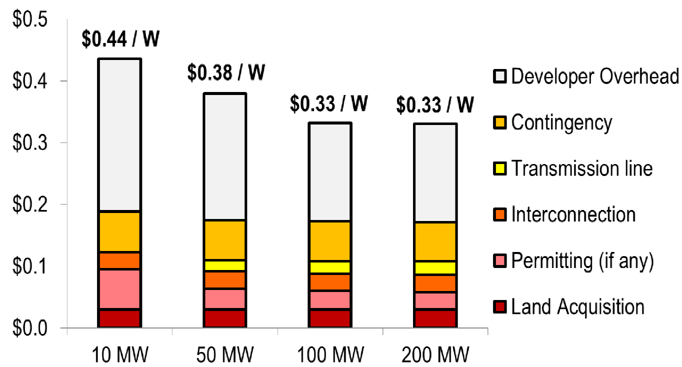

Fig. 5. 2015 "Developer Costs" breakdown in California (numbers from Table IV: system size=100 MW, non-union labor, fixed-tilt, module efficiency=16%).

TABLE IV. 2015 UTILITY-SCALE PV SYSTEM COST BREAKDOWN, $ PER WATT, IN DC TERMS (IN CALIFORNIA, MODULE EFFICIENCY = 16%)

	Non-Union Labor								Union Labor							
	Fixed Tilt				One-Axis Tracker				Fixed Tilt				One-Axis Tracker			
	10 MW	50 MW	100 MW	200 MW	10 MW	50 MW	100 MW	200 MW	10 MW	50 MW	100 MW	200 MW	10 MW	50 MW	100 MW	200 MW
PV module	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65
Inverter	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11
Racking + Tracker (if any)	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.22	$ 0.22	$ 0.22	$ 0.22	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.22	$ 0.22	$ 0.22	$ 0.22
BoS (Wiring, Conduit, etc.)	$ 0.18	$ 0.16	$ 0.16	$ 0.16	$ 0.18	$ 0.16	$ 0.16	$ 0.16	$ 0.18	$ 0.16	$ 0.16	$ 0.16	$ 0.18	$ 0.16	$ 0.16	$ 0.16
Labor + Equipment	$ 0.21	$ 0.21	$ 0.20	$ 0.20	$ 0.22	$ 0.22	$ 0.22	$ 0.22	$ 0.34	$ 0.34	$ 0.33	$ 0.33	$ 0.37	$ 0.37	$ 0.36	$ 0.36
EPC Overhead & Profit	$ 0.13	$ 0.12	$ 0.11	$ 0.11	$ 0.16	$ 0.15	$ 0.15	$ 0.15	$ 0.22	$ 0.21	$ 0.20	$ 0.20	$ 0.26	$ 0.25	$ 0.24	$ 0.24
Sale tax (if any)	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.10	$ 0.10	$ 0.10	$ 0.10
∑ EPC Cost	$ 1.53	$ 1.50	$ 1.49	$ 1.48	$ 1.64	$ 1.61	$ 1.60	$ 1.60	$ 1.75	$ 1.72	$ 1.70	$ 1.70	$ 1.89	$ 1.86	$ 1.84	$ 1.84
Land Acquisition	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03
Permitting (if any)	$ 0.06	$ 0.03	$ 0.03	$ 0.03	$ 0.07	$ 0.04	$ 0.03	$ 0.03	$ 0.06	$ 0.03	$ 0.03	$ 0.03	$ 0.07	$ 0.04	$ 0.03	$ 0.03
Interconnection	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03
Transmission line	$ -	$ 0.02	$ 0.02	$ 0.02	$ -	$ 0.02	$ 0.02	$ 0.02	$ -	$ 0.02	$ 0.03	$ 0.03	$ -	$ 0.02	$ 0.03	$ 0.03
Contingency	$ 0.07	$ 0.06	$ 0.06	$ 0.06	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.08	$ 0.08	$ 0.08	$ 0.08
Developer Overhead	$ 0.25	$ 0.21	$ 0.16	$ 0.16	$ 0.27	$ 0.22	$ 0.17	$ 0.17	$ 0.28	$ 0.23	$ 0.18	$ 0.18	$ 0.30	$ 0.25	$ 0.20	$ 0.20
∑ Developer Cost	$ 0.44	$ 0.38	$ 0.33	$ 0.33	$ 0.46	$ 0.40	$ 0.35	$ 0.35	$ 0.48	$ 0.42	$ 0.37	$ 0.37	$ 0.51	$ 0.45	$ 0.39	$ 0.39
∑ Total PV System Cost	$ 1.96	$ 1.88	$ 1.82	$ 1.82	$ 2.11	$ 2.02	$ 1.96	$ 1.95	$ 2.23	$ 2.14	$ 2.07	$ 2.07	$ 2.40	$ 2.31	$ 2.24	$ 2.24

In addition to the California case study, all other U.S. states are estimated in the model, depicting the regional cost difference due to the wind speed, snow loading, material cost index, labor rates, and sales tax. Fig. 6 shows three scenarios for EPC costs for all 50 U.S. states, Washington, D.C. and Puerto Rico: (1) fixed-tilt & non-union labor, (2) one-axis tracker & non-union labor, and (3) one-axis tracker & union labor.

Notably, union labor would significantly increase the EPC costs (EPC cost premium due to union labor: national median = \$0.13/W or 9%; California = \$0.24/W or 15%, and New York = \$0.25 or 16%).

Because of the lowest unionized labor rates (1.9% in Fig. 3) and moderate design criteria (105 mph wind speed, 10 PSF snow loading), North Carolina has the fifth-lowest modeled EPC costs—\$1.34/W for fixed-tilt & non-union labor, or \$1.44/W for one-axis tracker & non-union labor. This favorable EPC cost may in part contribute to North Carolina hosting the second-largest U.S. utility-scale PV installation capacity in 2014 (390 MW in Fig. 3). Nevertheless, North Carolina's Renewable Energy Portfolio Standard (REPS) and 35% state tax credit may be the primary reasons. Also notable, however, is the significant lagging of utility-scale development in the remaining lowest-cost states (Arkansas, Oklahoma, etc.), which illustrates the importance of market factors and policy incentives in utility-scale PV development.

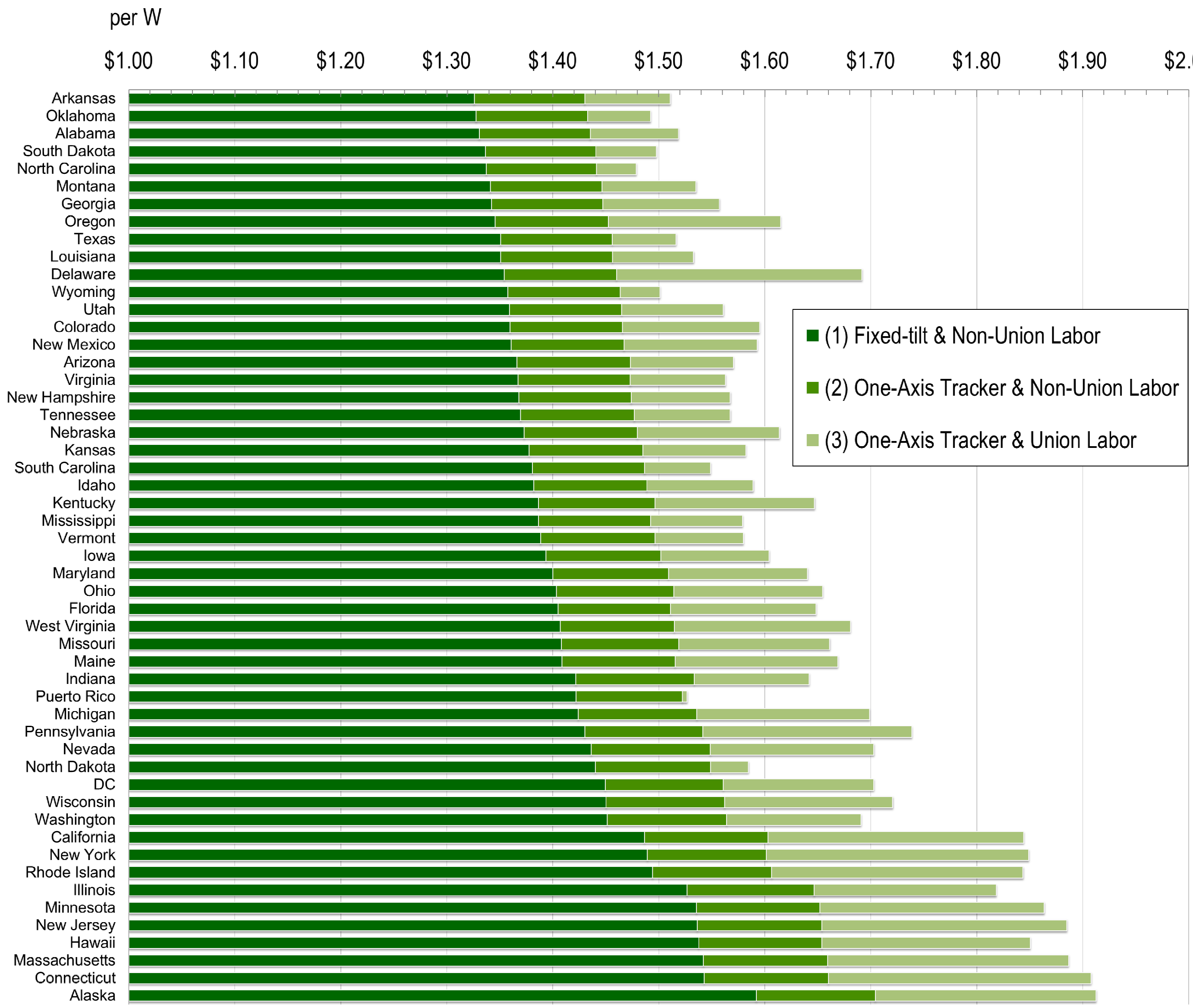

Fig.6. 2015 Modeled 100-MW Utility-Scale PV "EPC Costs" by region for three scenarios. \$ per Watt, in DC terms.

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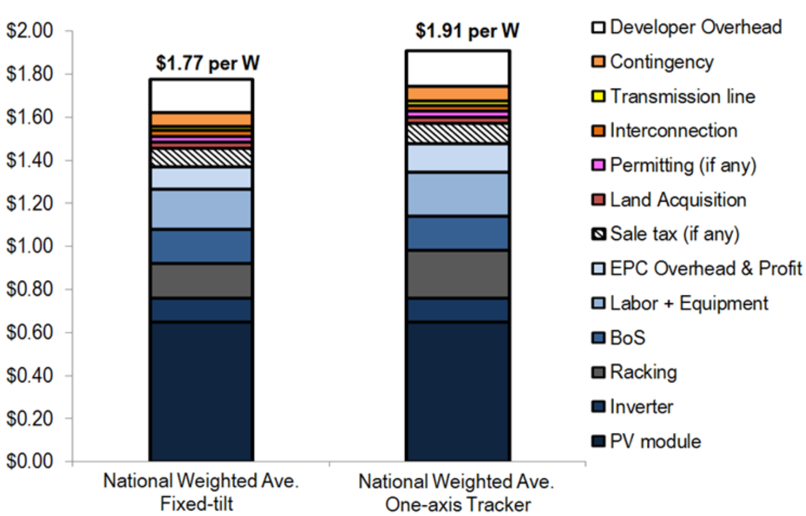
Table V shows the detailed "Total Installed Cost" breakdown for the top five largest, utility-scale, installation states in 2014. From Fig. 3, these five states are California (2,628 MW), North Carolina (390 MW), Nevada (318 MW), Arizon (103 MW), and Texas (99 MW).

Fig. 7 and its table below show the national weighted average "Total Cost" breakdown, using each state's utility-scale PV installation in 2014. Using non-union labor, for fixed-tilt systems, the modeled national weighted average is $1.77/W; for one-axis tracker systems, the modeled national weighted average is $1.90/W.

TABLE V

2015 UTILITY-SCALE PV SYSTEM "TOTAL INSTALLED COST" BREAKDOWN, $ PER WATT, IN DC TERMS (SYSTEM SIZE=100 MW, MODULE EFFICIENCY=16%)

	Non-Union Labor										Union Labor									
	Fixed Tilt					One-Axis Tracker					Fixed Tilt					One-Axis Tracker				
Top 5 States in 2014	CA	NC	NV	AZ	TX	CA	NC	NV	AZ	TX	CA	NC	NV	AZ	TX	CA	NC	NV	AZ	TX
PV module	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65
Inverter	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11
Racking + Tracker (if any)	$ 0.16	$ 0.17	$ 0.16	$ 0.16	$ 0.16	$ 0.22	$ 0.24	$ 0.22	$ 0.22	$ 0.23	$ 0.16	$ 0.17	$ 0.16	$ 0.16	$ 0.16	$ 0.22	$ 0.24	$ 0.22	$ 0.22	$ 0.23
BoS (Wiring, Conduit, etc.)	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Labor + Equipment	$ 0.20	$ 0.11	$ 0.18	$ 0.14	$ 0.12	$ 0.22	$ 0.12	$ 0.20	$ 0.15	$ 0.13	$ 0.33	$ 0.13	$ 0.28	$ 0.20	$ 0.16	$ 0.36	$ 0.15	$ 0.30	$ 0.21	$ 0.17
EPC Overhead & Profit	$ 0.11	$ 0.08	$ 0.09	$ 0.07	$ 0.07	$ 0.15	$ 0.11	$ 0.12	$ 0.10	$ 0.10	$ 0.20	$ 0.09	$ 0.14	$ 0.10	$ 0.09	$ 0.24	$ 0.12	$ 0.17	$ 0.13	$ 0.12
Sale tax (if any)	$ 0.09	$ 0.06	$ 0.08	$ 0.08	$ 0.07	$ 0.10	$ 0.06	$ 0.09	$ 0.08	$ 0.08	$ 0.09	$ 0.06	$ 0.08	$ 0.08	$ 0.07	$ 0.10	$ 0.06	$ 0.09	$ 0.08	$ 0.08
Σ EPC Cost	$ 1.49	$ 1.34	$ 1.44	$ 1.37	$ 1.35	$ 1.60	$ 1.44	$ 1.55	$ 1.47	$ 1.46	$ 1.70	$ 1.37	$ 1.58	$ 1.45	$ 1.40	$ 1.84	$ 1.48	$ 1.70	$ 1.57	$ 1.52
Land Acquisition	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03
Permitting (if any)	$ 0.03	$ 0.00	$ 0.03	$ 0.03	$ 0.00	$ 0.03	$ 0.00	$ 0.03	$ 0.03	$ 0.00	$ 0.03	$ 0.00	$ 0.03	$ 0.03	$ 0.00	$ 0.03	$ 0.00	$ 0.03	$ 0.03	$ 0.00
Interconnection	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03
Transmission line	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.03	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.03	$ 0.02	$ 0.02	$ 0.02	$ 0.02
Contingency	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.07	$ 0.06	$ 0.07	$ 0.06	$ 0.06	$ 0.07	$ 0.06	$ 0.07	$ 0.06	$ 0.06	$ 0.08	$ 0.06	$ 0.07	$ 0.07	$ 0.06
Developer Overhead	$ 0.16	$ 0.14	$ 0.15	$ 0.15	$ 0.14	$ 0.17	$ 0.15	$ 0.17	$ 0.16	$ 0.15	$ 0.18	$ 0.14	$ 0.17	$ 0.16	$ 0.15	$ 0.20	$ 0.16	$ 0.18	$ 0.17	$ 0.16
Σ Developer Cost	$ 0.33	$ 0.27	$ 0.32	$ 0.31	$ 0.28	$ 0.35	$ 0.29	$ 0.34	$ 0.33	$ 0.29	$ 0.37	$ 0.28	$ 0.35	$ 0.33	$ 0.28	$ 0.39	$ 0.29	$ 0.37	$ 0.35	$ 0.30
Σ Total PV System Cost	$ 1.82	$ 1.61	$ 1.76	$ 1.68	$ 1.63	$ 1.96	$ 1.73	$ 1.89	$ 1.80	$ 1.75	$ 2.07	$ 1.65	$ 1.92	$ 1.78	$ 1.69	$ 2.24	$ 1.77	$ 2.07	$ 1.92	$ 1.82



	Non-Union Labor	
	National Weighted Ave. Fixed-tilt, 100 MW	National Weighted Ave. One-axis Tracker, 100 MW
PV module	$ 0.65	$ 0.65
Inverter	$ 0.11	$ 0.11
Racking + Tracker (if any)	$ 0.16	$ 0.22
BoS (Wiring, Conduit, etc.)	$ 0.16	$ 0.16
Labor + Equipment	$ 0.19	$ 0.20
EPC Overhead & Profit	$ 0.10	$ 0.14
Sale tax (if any)	$ 0.09	$ 0.09
Σ EPC Cost	$ 1.46	$ 1.57
Land Acquisition	$ 0.03	$ 0.03
Permitting (if any)	$ 0.02	$ 0.03
Interconnection	$ 0.03	$ 0.03
Transmission line	$ 0.02	$ 0.02
Contingency	$ 0.06	$ 0.07
Developer Overhead	$ 0.16	$ 0.17
Σ Developer Cost	$ 0.32	$ 0.34
Σ Total PV System Cost	$ 1.77	$ 1.91

Fig.7. 2015 Modeled national weighted average using 2014 U.S. installation. $ per Watt, in DC terms.
(For a 100 MW utility-scale system with 16% module efficiency)

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IV. Results from Utility-Scale PV System Model: LCOE

To estimate LCOEs across the U.S., the modeled total installed cost (from Section III) are combined with localized solar irradiance and weather data, a PV performance model, and a *pro forma* financial analysis that models the revenue, operating expenses, taxes and incentives, debt structures, and cash flows for a representative PV system. SAM, a performance and financial model developed by NREL [21], is used to estimate a PV system's location-specific hourly energy output over the system's lifetime, and subsequently calculate the resulting real LCOEs (considering inflation) for each location. Fig. 8 presents the real LCOEs of a fixed-tilt and one-axis tracker for regions across the U.S. including regional labor and material costs, wind speed, snow loading, solar irradiance and weather data, and sales tax. Table VI contains all the inputs in SAM for preparing Fig. 8.

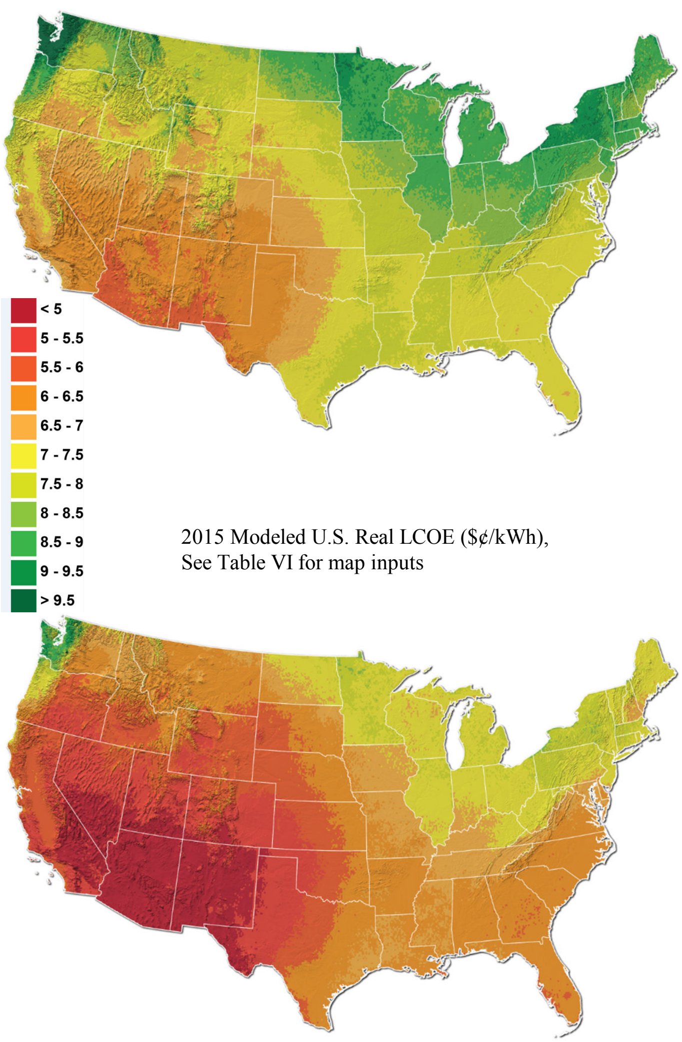

Fig. 8. 2015 modeled real LCOE ($¢/kWh) for a 100-MW utility-scale PV system: the upper map is for fixed-tilt systems, and the lower is for one-axis tracker systems. See Table VI for all inputs and assumptions.

TABLE VI
INPUTS IN SAM FOR LCOE CALCULATIONS

	Fixed-tilt	One-axis Tracker
Module	Trina Solar TSM-310PD14 Note: both module and inverter are selected from the SAM database for the calculation purpose. Other products can also be used in the SAM.	
Inverter	SMA American SC500CP-US 600V	
System size (DC)	100 MW	
DC to AC ratio (or inverter loading ratio) [8]	1.40 (oversized)	1.20
	Note: for traditional designs, this ratio is within 1.1~1.2 range. However, due to the module price decline, the design focus has been shifting from production efficiency to financial efficiency.	
Backtracking	N/A Tilt angle = 33 degree	Yes, and Ground coverage ratio = 0.3
Power loss	Total DC power loss = 4.4% Total AC power loss = 1%	
Total installed cost	From Table V, for instance, California is:	
	$1.82/W	$1.96/W
Fixed O&M cost	$15/kW per year	$18/kW per year
	One-axis tracker has additional O&M costs due to grease lubrication, on-site technicians, spare parts, etc. [8].	
Degradation rate	0.5% per year	0.5% per year
Discount rate	Nominal discount rate = 7.01% (Inflation = 2.5%, Real discount rate = 4.4%) Analysis period = 30 years Note: "PPA single owner" is used in SAM. A 50/50 split is assumed for tax and sponsor equity in a partnership flip structure with no project-level debt [22].	
IRR target	IRR target = 7.01% (after-tax IRR) IRR target year = 30 years to achieve IRR target PPA price escalation = 2.5% (same as inflation) Note: IRR target is set to be the same as nominal discount rate. Thus, for outputs in the SAM, LCOE = PPA for both nominal and real terms.	
Tax rates and insurance	Federal income tax rate = 35% State income tax rate = vary by state Insurance rate = 0% (considered in the O&M)	
Net salvage value	$0	$0
Project term debt	No project term debt	
Cost of acquiring financing	$0	$0
Construction financing	One loan, 1% up-front fee, 6 months prior to operation, 4% annual interest rate	
Reserve accounts	No reserve accounts; Replace inverters for $0.15/W for every 12 years	
Time of delivery	Generic Summer Peak	
Incentives	Federal ITC = 30%, State ITC = 0% Other incentives = 0%	
Depreciation	5-year MACRS, No bonus depreciation	

Several typical utility-scale PV locations are selected to demonstrate the nominal LCOE and the real LCOE (assuming inflation = 2.5%) for fixed-tilt and one-axis tracker systems, shown in Fig. 9 and Table VII. Note that in this paper, the IRR target is set to be the same as nominal discount rate. Thus, for outputs in the SAM, LCOE = PPA for both nominal and real terms. For instance, for Bakersfield in CA, nominal LCOE = levelized nominal PPA price = 9.49 cent ($) per kWh, and project NPV = 0.

In Table VII, although one-axis trackers have to bear 7-8% total installed cost (= EPC + Developer costs) premiums, the resulting significant nominal and real LCOEs, or levelized PPA prices, reductions would be more economically compelling for investors to choose solar tracking systems, especially in high solar irradiance southwestern states such as California, Arizona, Nevada, New Mexico, Utah, and Colorado. In those states, the economic benefits of a one-axis tracker, in terms of lower LCOEs, are estimated at 17%~21%.

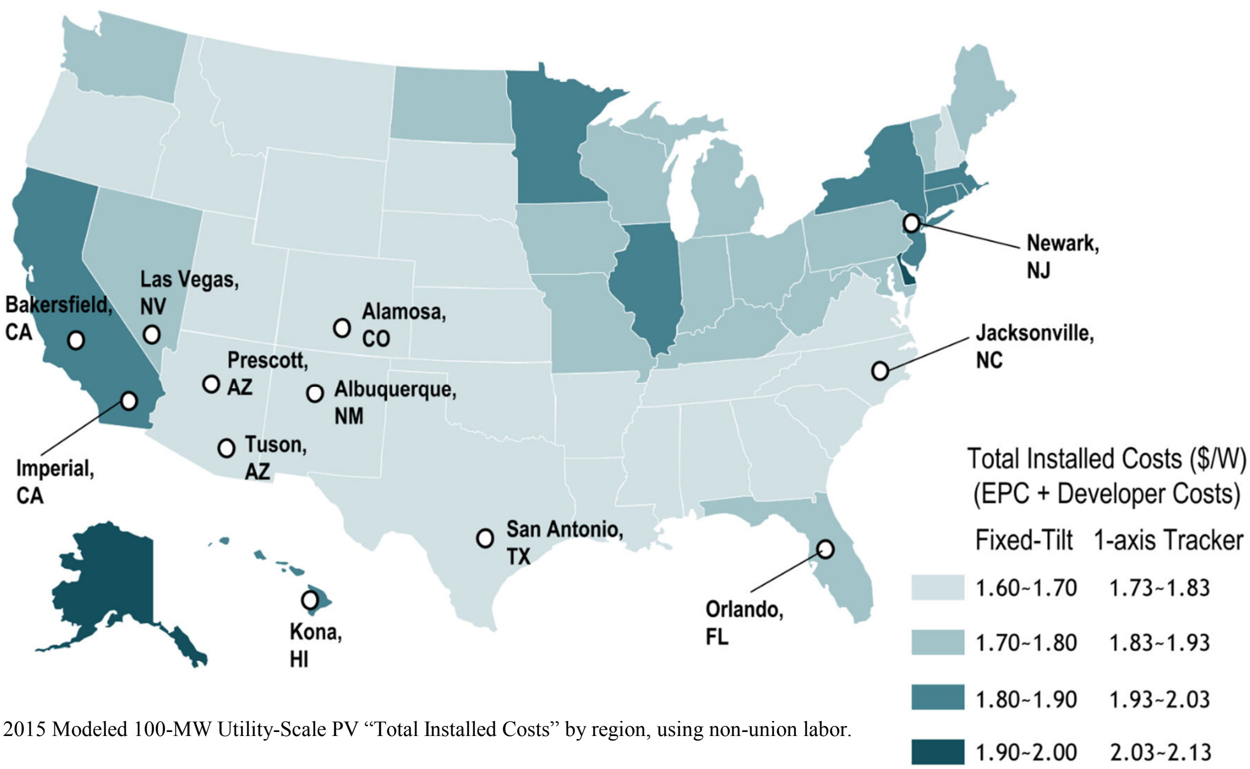

Fig.9. 2015 Modeled 100-MW Utility-Scale PV “Total Installed Costs” by region, using non-union labor.

TABLE VII
2015 MODELED UTILITY-SCALE PV FOR INSTALLED COST, NOMINAL LCOE, AND LEVELIZED PPA FOR SELECTED LOCATIONS

		Fixed-Tilt			One-Axis Tracker			One-Axis Tracker vs. Fixed-Tilt		
State	Location	Total Installed Costs ($/W)	Nominal LCOE (cent per kWh)	Real LCOE (cent per kWh)	Total Installed Costs ($/W)	Nominal LCOE (cent per kWh)	Real LCOE (cent per kWh)	Installed Costs Premium (%)	Nominal LCOE Reduction (%)	Real LCOE Reduction (%)
CA	Bakersfield	$ 1.82	$ 9.49	$ 7.20	$ 1.96	$ 7.85	$ 5.95	7.69%	-17.28%	-17.36%
CA	Imperial Valley	$ 1.82	$ 8.58	$ 6.50	$ 1.96	$ 6.99	$ 5.30	7.69%	-18.53%	-18.46%
AZ	Prescott	$ 1.68	$ 8.34	$ 6.33	$ 1.80	$ 6.66	$ 5.05	7.14%	-20.14%	-20.22%
AZ	Tuson	$ 1.68	$ 8.04	$ 6.10	$ 1.80	$ 6.46	$ 4.90	7.14%	-19.65%	-19.67%
NV	Las Vegas	$ 1.76	$ 8.34	$ 6.32	$ 1.89	$ 6.70	$ 5.08	7.39%	-19.66%	-19.62%
NM	Albuquerque	$ 1.67	$ 8.11	$ 6.15	$ 1.80	$ 6.60	$ 5.00	7.78%	-18.62%	-18.70%
CO	Alamosa	$ 1.67	$ 8.13	$ 6.16	$ 1.80	$ 6.48	$ 4.91	7.78%	-20.30%	-20.29%
NC	Jacksonville	$ 1.61	$ 9.51	$ 7.21	$ 1.73	$ 8.08	$ 6.12	7.45%	-15.04%	-15.12%
TX	San Antonio	$ 1.63	$ 9.38	$ 7.11	$ 1.75	$ 8.04	$ 6.10	7.36%	-14.29%	-14.21%
NJ	Newark	$ 1.84	$ 11.78	$ 8.93	$ 1.98	$ 10.33	$ 7.83	7.61%	-12.31%	-12.32%
FL	Orlando	$ 1.69	$ 10.58	$ 8.02	$ 1.81	$ 9.11	$ 6.91	7.10%	-13.89%	-13.84%
HI	Kona	$ 1.88	$ 10.38	$ 7.87	$ 2.02	$ 8.93	$ 6.77	7.45%	-13.97%	-13.98%

Also, for large-scale PV systems in those southwestern regions, developers could use a one-axis tracker to lower the PPA price during the contract negotiation to provide a more competitive bid than a fixed-tilt system.

It is worth noting that, for other low solar irradiance areas (North Carolina, Texas, New Jersey, Florida, and Hawaii in Table VII), one-axis tracker can still provide 12%~16% LCOE reductions. Nevertheless, the one-axis tracker implementations in those areas are relatively slow, because those area may have geotechnical issues, such as unfavorable soil condition and small open space for large utility-scale systems which require lower ground coverage ratio (GCR, 0.3~0.4 for one-axis tracker) than fixed-tilt systems.

V. Impact of Module Efficiency on Installed Costs

In addition to the installed cost and LCOE estimates, the system cost model is also used to assess the economic benefits of high module efficiency on the installed cost savings, as shown in Fig. 10. Because higher module efficiency will reduce the number of modules required to reach a certain system DC size, the related racking/mounting hardware, foundation, BoS, EPC/developer overhead, and labor hours to install a certain amount of materials will be reduced accordingly. This analysis holds module prices equal for any given efficiency, and demonstrates that higher efficiencies can help reduce total system installed costs.

The degree of impact varies by the analysis boundary conditions (either fixed system area or fixed system DC capacity), but in all cases examined, higher efficiencies resulted in lower system installed costs. For instance, starting from Point B (100-MW, 580-Acre, 16% module efficiency, \$1.82/W installed cost), there are two cases:

(1) If the system size, 100 MW, is fixed and only system area can be changed, then 60% module efficiency (a hypothetical assumption. Not possible for any single-junction cells, including crystalline silicon, but it is possible for multi-junction cells [23]) would result in \$1.33/W installed cost and 155-Acre because, in order to reach the same 100 MW system size, fewer modules would be required – which leads to lower installed cost and a smaller system area.

(2) If the system area, 580-Acre, is fixed and only system size can be changed, then 60% module efficiency would result in \$1.30/W installed cost and 375 MW because, in order to occupy the same 580-Acre area (namely, the same number of modules), more power would be generated with high module efficiency – which leads to lower installed cost and larger system size.

Most importantly, although system cost savings can be achieved by using high-efficiency modules, the \$1/W SunShot target for utility-scale PV installed cost may not be achieved solely by module efficiency improvements due to the diminishing cost savings illustrated in Fig. 10. Therefore, research for reducing other cost categories (shown in Fig. 2 and Fig. 7) including soft cost, racking cost, tracker cost (if any), and BoS cost are already critical for the PV industry.

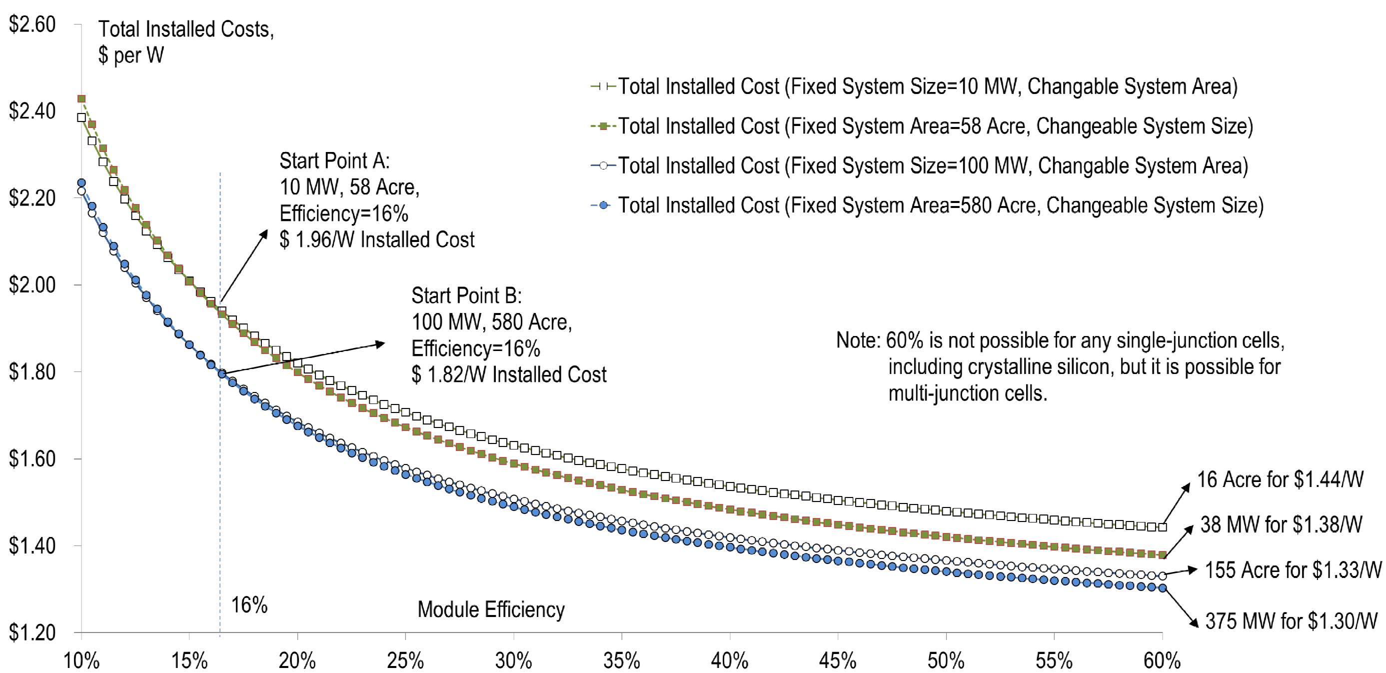

Fig. 10. Modeled utility-scale PV fixed-tilt system "Total Installed Cost" reduction by using high efficiency modules (assuming fixed module price \$0.65/W and inverter price \$0.11/W, in California).

VI. Summary of Results

The economic competitiveness of U.S. utility-scale PV systems in 2015 is analyzed in terms of total installed cost and LCOE by using a granular bottom-up cost model with regional attributes that assesses location-specific cost factors. Significant regional variations in total installed costs (especially for EPC costs) and LCOE are spatially presented in maps in Figs 8 and 9. Key findings in this paper are as below:

(1) The 2015 national weighted average costs are benchmarked in Fig. 7: For a 100 MW utility-scale system, EPC cost using fixed-tilt = \$1.46/W; EPC cost using one-axis tracker = \$1.57/W; developer cost using fixed-tilt = \$0.32/W; developer cost using one-axis tracker = \$0.34/W; total installed cost using fixed-tilt = \$1.77/W; total installed cost using one-axis tracker = \$1.91/W.

(2) For 2015 regional cost benchmarking, Table IV, Table V and Fig. 6 contain detailed cost breakdowns. In California, for instance, for a 100 MW utility-scale system, EPC cost using fixed-tilt = \$1.49/W; EPC cost using one-axis tracker = \$1.60/W; developer cost using fixed-tilt = \$0.33/W; developer cost using one-axis tracker = \$0.35/W; total installed cost using fixed-tilt = \$1.82/W; total installed cost using one-axis tracker = \$1.96/W.

(3) Based on the modeled results in Table IV, the impact of economies of scale on total installed costs is generally modest, but is more notable for developer costs than EPC costs primarily due to the decreasing permitting costs and developer overhead.

(4) Non-union labor and union labor costs are compared, with union labor premiums varying significantly across the country, as presented in Fig. 6. If union labor is used in our model, EPC costs would largely be increased—EPC cost premium due to union labor: national median = \$0.13/W or 9%; California = \$0.24/W or 15%, and New York = \$0.25/W or 16%.

(5) Although a one-axis tracking system incurs a cost premium compared to a fixed-tilt systems (\$0.10~\$0.12/W for EPC cost premium, and \$0.12~\$0.14/W for total installed cost premium), significant nominal and real LCOE, or PPA price, reductions for a one-axis tracker system can be realized for investors who retain and operate the solar asset for its useful life due to the increased energy production enabled. Those LCOE and PPA reductions by using one-axis tracking systems are more remarkable (17%~21%) in U.S. southwestern states than other states (12%~16%), presented in Table VII.

(6) Finally, installed cost reductions through the use of high efficiency modules are also analyzed for the purposes of future R&D scope and focus. The diminishing total installed cost saving by using high-efficiency modules in Fig. 10 indicates the importance of additional focus on other system component cost (racking, BoS, soft cost, etc.) reduction in today's research in order to achieve U.S. DOE SunShot targets.

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